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16. ABSTRACT

The paper examines water-related effects that could be expected from siting specific conversion plants at given locations in the major coal and oil shale bearing regions of the U.S. A total of 90 plant/site combinations were studied: 48 in the Central and Eastern U.S., and 42 in the Western. The synthetic fuel technologies examined include: coal gasification to convert coal to pipeline gas; coal liquefaction to convert coal to low-sulfur fuel oil; coal refining to produce a de-ashed, low-sulfur solvent-refined (clean) coal; and oil shale retorting to produce synthetic crude. The results presented include the range of water requirements, the conditions for narrowing the range and optimizing the use of water, the ranges of residual solid wastes, and the cost and energy requirements for wastewater treatment. A comparison of the water requirements with those of two recently published studies shows widely varying estimates and emphasizes the need for both site- and design-specific calculations.

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Coal		Solvent Refined Coal	

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Pollution Control Practices—

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Fuel Conversion And Its Environmental Effects

Unless properly treated, water and air discharges contaminated with organic materials may pose the greatest potential threat to the environment from the emerging energy technologies.

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Development of a synthetic fuel industry in the United States could be severely impaired because of local environmental problems associated with the large consumptive use of water required for coal and oil shale conversion processing, and because of the large quantities of environmentally unacceptable solid wastes that leave these plants and for which a disposal site must be found. Moreover, water for synthetic fuel development in a given location, where coal can be economically mined, may be in short supply; or there may be strong competition for the water among alternative uses including agricultural, power production, municipal, industrial, and recreational.

High water consumption has been a frequent reason cited for stifling the development of a synthetic fuel industry, particularly in the water-short western states. These high water consumption estimates may be both excessive and misleading. They may be excessive because of the large quantity of water assumed to be evaporated for cooling, since cooling water is most often the prime determinant of total consumption. They may be misleading because the estimates, with few exceptions, have been regional, rather than derived from local site-, process- and design-specific calculations.

The objective of the work presented in this article was to determine the feasibility of siting specific conversion plants at given locations in the major U.S. coal and oil shale bearing regions; and the extent of the environmental impacts that could be expected from local water-related

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Table 1. Summary of results by conversion process.

	Reactor Type	Mining Rates (lb/million Btu) Lignite	Sub-bituminous	Bituminous	Net Water Consumption (gal/million Btu) High Wet Cooling	Intermediate Wet Cooling	Minimum Practical Wet Cooling	Wet Solid Residuals (lb/million Btu)	Water Treatment Cost (¢/million Btu)	Water Treatment Energy (% Prod. Energy)
Coal Gasification										
Lurgi	Fixed Bed	250–360	160–220	140–160	18–30	9–22	7–21	59–126	5.4–14.0	2.3–8.3
Synthane	Fluid Bed	250*	180–220*	130–160	22–27	16–19	15–17	40–56	1.7–4.3	1.3–2.2
Hygas	Fluid Bed Hydrogasifier	200–240	120–180	110–140	21–26	16–19	15–19	32–64	2.3–4.1	1.0–4.0
Bigas	Entrained Flow	220–270	—	110–140	25–27	16–18	14–17	27–61	1.6–2.8	1.7–3.0
Coal Liquefaction										
Synthoil	Catalytic Fixed Bed	—	120–170	100–120	17–21	11–14	10–14	7–28	0.3–1.1	0.04–0.6
Coal Refining										
SRC	Dissolver	180–280	160–180	110–140	13–21	8–13	7–11	12–40	0.7–1.6	0.1–1.0
Oil Shale			*High Grade Shale*							
Paraho Direct	Direct Retorting		630			18		520		
Paraho Indirect	Indirect Retort		720			28		630		
TOSCO II	Indirect Retort		510			29		470		

*Data from Ref. 2. Refers only to number and not to range.
Metric conversions: 1 lb/million Btu = 0.43 kg/million kJ
1 gal/million Btu = 3.59 m³/billion kJ
1¢/million Btu = 0.95¢/million kJ

site, process and plant design criteria. Of the 90 plant-site combinations studied, 48 were in the central and eastern coal bearing regions and 42 in the western coal and oil shale bearing regions. The plants were assumed to be designed so as not to waste water. Effluent process waters were assumed to be reused, and different cooling options were selected based on the availability and cost of water. Estimates were made of the total net water consumed, wet solid residuals generated, and the cost and energy required for water treatment for each plant-site combination and then generalized to each one of the major U.S. coal and oil shale bearing regions.

In this article the data are summarized for a number of conversion processes without distinguishing between coal rank or coal and oil-shale bearing region. These data have been generalized from individual plant-site results. Details of the complete study are reported by Gold and Goldstein (*1*) and Probstein and Gold. (*2*)

Process and site selection

The synthetic fuel technologies examined include coal gasification to convert coal to pipeline gas; coal liquefaction to convert coal to low sulfur fuel oil; coal refining to produce a de-ashed, low-sulfur, solvent-refined (clean) coal; and oil shale retorting to produce synthetic crude. A number of processes were chosen for each conversion.

Detailed conceptual designs for integrated mine-plant complexes were made for each of the representative conversion processes to compare water requirements, types of water treatment plants, and the quantities of wet-solid residuals generated. Specific designs discussed by Gold and Goldstein (*1*) are based on coal gasification plants producing 250 million std cu ft/day (7.08 million m^3/d) of pipeline gas, coal liquefaction plants producing 50,000 barrels/day (7,960 m^3/d) of fuel oil, coal refining plants producing 10,000 ton/day (9,070 metric t/d) of solvent refined coal, and oil shale plants producing 50,000 barrels/day (7,960 m^3/d) of synthetic crude.

Many site and process criteria combinations were studied to obtain meaningful assessments on a regional and national level from detailed local results. Process criteria for the conversion of coal have been defined based upon the quality of the foul condensate recovered after gasification or liquefaction.

Low-temperature gasifiers (e.g., Lurgi and Synthane) produce a very dirty process condensate (typical values for bituminous coals: BOD ~ 10,000 mg/l, phenol ~ 3,000 mg/l, and ammonia ~ 7,000 mg/l). High-temperature gasifiers (e.g., Koppers-Totzek and Bigas) produce a relatively clean condensate (typical values: ammonia ~ 4,500 mg/l, BOD and phenol ~ small). The intermediate temperature Hygas gasifier produces a process condensate of intermediate quality. Both the Solvent Refined Coal (SRC) and Synthoil processes have the foulest condensates.

For oil shale conversion, the degree of water management depends on the type of retort used. For direct-heated retorting processes (e.g., Paraho Direct), most of the water is recovered; however, for indirect-heated processes (e.g., Paraho Indirect and TOSCO II), the water in the combustion products is generally lost up the furnace stack and not recovered.

As for site criteria, brackish ground water would have to be considered an important conjunctive supply to surface waters in the West, while surface waters are considered primarily in the East. Eastern and central states have humid climates, while climates in the West are arid and semi-arid. Eastern and central coals are both underground and surface mined, while western coals are primarily surface mined. In the West, underground mining followed by surface retorting of oil shale has been investigated extensively. *In-situ* retorting was not considered in the present study because it is still under development and cannot yet be considered commercially.

Site selection was based primarily on the availability of coal and oil shale, the rank of coal or oil shale, the type of mining (underground or surface) and the availability of surface and groundwater. Coal mining regions chosen were those where the largest and most easily mined deposits are located. In the West, these include the Powder River and Ft. Union regions in Montana, Wyoming, and North Dakota, and the Four Corners region in New Mexico. In the central and eastern regions, the Illinois and Appalachian coal basins were selected. The western coals are principally low-sulfur sub-bituminous and lignite, while eastern and central coals are mainly high-sulfur bituminous. The only

Table 2. Overall conversion efficiency and percentage unrecovered heat dissipated by wet cooling.

Technology and Conversion Process	Overall Conversion Efficiency, %	Unrecovered Heat Dissipated by Wet Cooling, %		
		High Wet Cooling	Intermediate Cooling	Minimum Practical Cooling
Coal Gasification:				
Lurgi	65–67	33	18	15
Synthane	65–73	30–33	15–18	12–16
Hygas	65–74	23–35	13–20	11–17
Bigas	66–70	40–46	20–21	16–17
Coal Liquefaction:				
Synthoil	72–79	44–54	25–36	22–33
Coal Refining:				
SRC	59–82	34–51	18–33	15–30
Oil Shale:				
Paraho Direct	71		28	
Paraho Indirect	57		19	
TOSCO II	68		18	

oil shale considered was high-grade shale from the Green River Formation. Specific design examples were restricted to shales with yields of about 30 to 35 gal/ton (0.13 to 0.15 m^3/metric ton), as might be found in Colorado or Utah.

The process-site results are summarized in Table 1. They are presented by conversion process with no distinction made between coal rank, except for the mining rates. Results have been normalized with respect to the heating value of the product. The difference in mining rates is due to the variation in the heating values of the different rank coals and the diffferent conversion efficiencies of the processes considered. A further breakdown by coal and oil shale bearing region is given by Gold and Goldstein. (*1*)

Water Consumption

Estimates of water consumption are net; all effluent streams are assumed to be recycled or reused within the mine or plant after any necessary treatment. These streams include the organically contaminated waters generated in the conversion process, which are unfit for disposal without treatment, and the highly saline water blown down from evaporative cooling systems. Water is only released to evaporation ponds as a method of salt disposal. However, these wastes may be disposed of with the coal ash if the problems of runoff and groundwater contamination are adequately handled in an economic manner. The rest of the water consumed leaves the plant as vapor, as bonded hydrogen after hydrogenation, or as occluded water in the solid residues. Dirty water is cleaned, but only for reuse and not for returning it to a receiving water.

In general, the total quantity of net water consumed depends primarily on the quantity of water evaporated in cooling. The cost and availability of water determine the degree to which wet cooling should be used. Three cooling options were considered representing different kinds of wet evaporative cooling for turbine condensers and gas-compressor interstage coolers.

Where water is plentiful and inexpensive to transport, high wet cooling should be used. The cooling loads on both the turbine condensers and interstage coolers are taken to be all wet-cooled. For the Lurgi process a detailed thermal balance was not available: wet cooling was assumed to be used to dispose of 33% of the total unrecovered heat. The same value was one estimated for the Synthane process since the two processes are thermally similar. This value falls within the range of Lurgi design data. The El Paso design indicates that 36% of the unrecovered heat is dissipated by evaporative cooling, while the Wesco design indicates 26%.

Where water is marginally available or moderately expensive to transport, intermediate cooling should be used. Intermediate cooling assumes that wet cooling handles 10% of the cooling load on the turbine condensers and all of the load on the interstage coolers. For the Lurgi process, 18% of the unrecovered heat is assumed to be dissipated by wet cooling. Again, this is based on Synthane process estimates. The oil shale processes are assumed to use an intermediate degree of wet cooling. For the Paraho Direct process, 28% of the unrecovered heat is dissipated by wet cooling. For both the Paraho Indirect and TOSCO II processes 18–19% is dissipated.

Where water is scarce or expensive to transport, minimum practical wet cooling should be used. Minimum practical wet cooling assumes that wet cooling dissipates 10% of the cooling load on the turbine condensers and 50% of the load on the interstage coolers. For this case, the Lurgi process is assumed to dissipate 15% of the unrecovered heat by wet cooling; again it is based on the estimates for the Synthane process.

If water costs more than about \$1.50/1,000 gal (\$0.40/m^3) minimum practical cooling would be used. Intermediate cooling would be used if the water cost is between \$0.20 and \$1.50/1,000 gal (\$0.05 and \$0.40/m^3). High wet cooling would be used if water costs less than \$0.20/1,000 gal. For example, in the western coal and oil shale bearing regions, except for plants located near the main stems of major rivers, intermediate or minimum practical wet cooling would be used based on the cost of transporting water to the sites. In the eastern and central regions, where a number of large rivers contiguous or adjacent to many of the study sites can provide a sufficient and reliable supply of water to support one or more large mine-plant coal conversion complexes, a high degree of wet cooling would be used.

However, water supplies are much less reliable in the smaller streams away from the major rivers. In some areas extremely low flows occur seasonally, and a coal conversion complex could easily represent a significant portion of the

Table 3. Comparison of net water consumed, gal/million Btu[a].

Technology	Harte Study (5)	ERDA Report (6)	Present Study
Coal Gasification (Pipeline Gas):			
Eastern Coals	25–173	66–69[b] 124–126[c]	7–28
Western Coals	25–212	27–32[b] 56–60[c]	12–30
Coal Liquefaction			
Eastern Coals	25–221	100–114	12–21
Western Coals	25–271	44–48	10–19
Coal Refining			
Eastern Coals	—	20–22	6–17
Western Coals	—	10[d]	7–21
Oil Shale			
Surface Mine	19–28	19–27	—
Underground Mine	18–30	19–31	18–29

[a]1 gal/million Btu = 3.59 m^3/billion kJ. [b]Fixed bed gasifier. [c]Fluidized bed gasifier. [d]Includes moisture in raw coal.

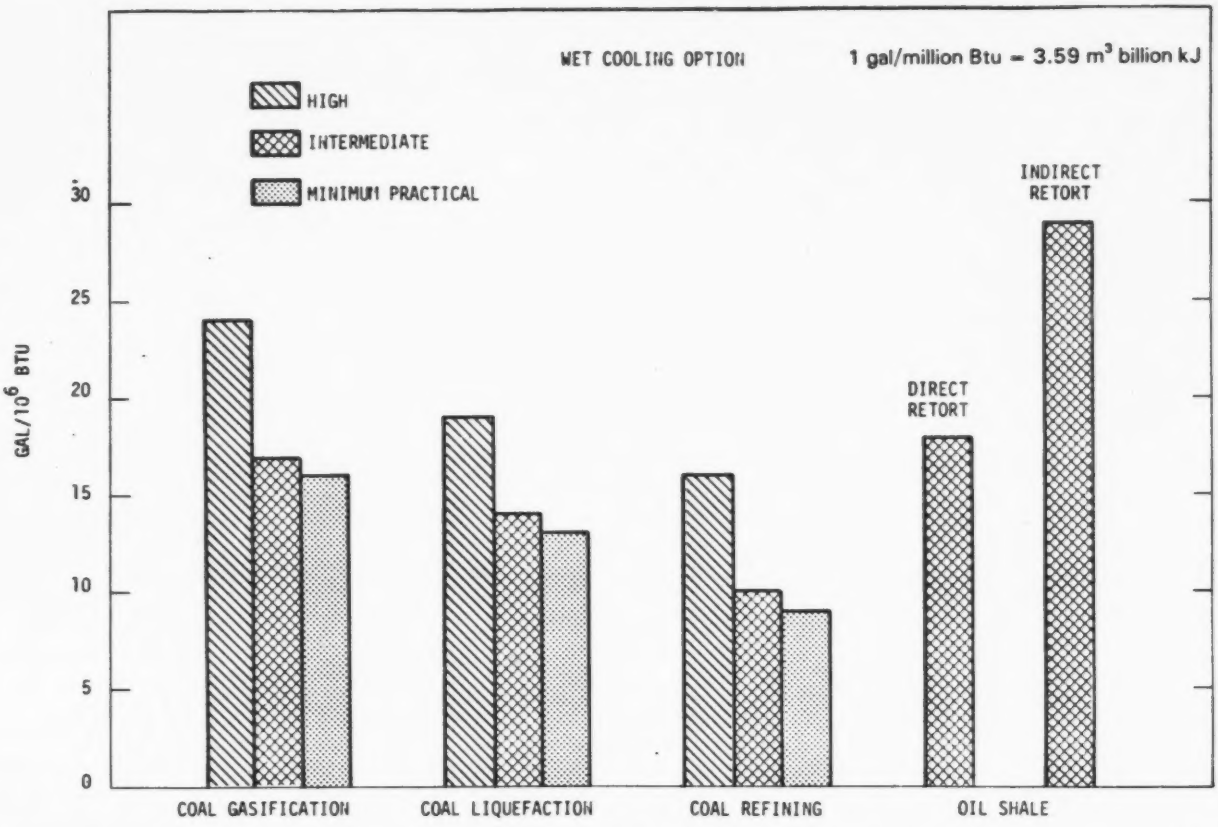

Figure 1. Average total water consumed by fuel conversion processes, normalized with respect to heating value of product fuel.

low flow. In order for a plant to be sited in these areas, an alternative or supplemental supply must be assured and intermediate or minimum practical wet cooling would be used in the plant.

High wet cooling does not mean that all of the unrecovered heat is dissipated by wet cooling, since an appreciable fraction will be lost directly to the atmosphere. Minimum practical wet cooling does not mean that none of the unrecovered heat is dissipated by wet cooling, since this is not economical.

For a given size conversion plant, the quantity of water consumed by cooling mainly depends on the overall conversion efficiency and the percentage of unrecovered heat dissipated by wet cooling. All of the unrecovered heat not dissipated by wet cooling is lost directly to the atmosphere while the rest of the heat is transferred to the atmosphere by direct cooling.

Table 2 lists the range of conversion efficiencies for each conversion process as well as the percentage of unrecovered heat dissipated by wet cooling for each of the three cooling options. The low conversion efficiencies for the SRC process correspond to sites utilizing wet lignites and are attributable to large quantities of energy required for coal drying prior to processing.

For coal gasification and liquefaction the total net water consumption with intermediate wet cooling is about 72% of the total net water consumption for high wet cooling, and 66% with minimum practical wet cooling. The percentages for coal refining are 63 and 56%, respectively.

Besides cooling, the water consumption estimates include the process water requirements, the water required for the mining and preparation of the coal and shale, and for the disposal of ash or spent shale, which is a function of location through the amount of material that must be mined or disposed. Sulfur removal also consumes water; The amount depends not only on the coal, but also on the conversion process. Water is also needed for a number of other purposes (e.g., land reclamation) that depend on climate.

Generally, any one requirement is not large and the needs can be met with lower quality water. Nevertheless, when the requirements are taken together, they are significant and cannot be neglected in any plant water balance, although general rules for the amount consumed are not easily stated. Differences in consumption in this category for a given coal conversion process, however, do not vary by more than 15% between regions, except for the Four Corners region. The difference is somewhat greater when this region is compared with others, since larger amounts of water are needed there for handling the high ash Navajo coal and for dust control and revegetation.

Gasification has greatest needs

In general, the net water requirements are largest for coal gasification, followed by coal liquefaction and coal refining. The difference between the latter two processes is relatively small. The differences in net water consumption as a function of coal rank are small, except for the Lurgi process for which the smallest requirement is for wet lignite coals. The Lurgi process accepts wet coal and the large quantities of dirty condensate produced are treated for reuse and are subtracted from the process requirement.

For intermediate wet cooling the water requirements

for the Paraho Direct process are comparable with those for the Synthoil process, which produces roughly the same product. However, the Paraho Indirect and TOSCO II processes have the largest net water requirements due mainly to the larger requirements for spent shale disposal and revegetation.

The maximum difference in water consumption for coal gasification between high cooling and minimum practical wet cooling is a factor of about 4, pointing up the importance of the choice of process and cooling design in the amount of water consumed in synthetic fuel production. The maximum difference in water consumption between high wet cooling and minimum practical wet cooling at a given coal gasification site is approximately 10 gal/million Btu (36 m^3/billion kJ).

Minimum practical wet cooling will be used if water is relatively expensive, that is about \$1.50/1,000 gal (\$0.40/m^3) or more. Even so, minimum practical cooling will cost about 1.5¢/million Btu (1.4¢/million kJ) more than high wet cooling because of the higher annual capital investment costs of dry cooling systems.

In a particular coal-bearing region, differences in the water requirements between the four coal gasification processes that we have considered are due principally to the differences in the process water requirement and in the estimated overall plant efficiency resulting in different cooling water requirements.

For each process the average water consumed is relatively insensitive to the coal-bearing region; variations for a given cooling option from site to site within the region are small for all of the processes, except possibly for the Lurgi and SRC processes, for reasons that were discussed above. However, within a given region there might be large variations in water availability and water costs; different cooling options at different sites will produce large differences in cooling water consumption and plant water requirements.

Figure 1 shows the average total water consumed normalized with respect to the heating value of the product fuel: Coal rank and regional differences are averaged out for each coal conversion technology.

Solid residues generated in coal and oil shale conversion plants are generally disposed of wet with occluded water. The principal residuals in coal conversion plants are coal ash and where flue gas scrubbing is used, flue gas desulfurization sludge. In oil shale plants, the principal residual is spent shale. Sludges from water treatment plants have also been considered. Between 3,000 and 15,000 ton/day (2,700 and 13,600 metric t/d) of wet solids are

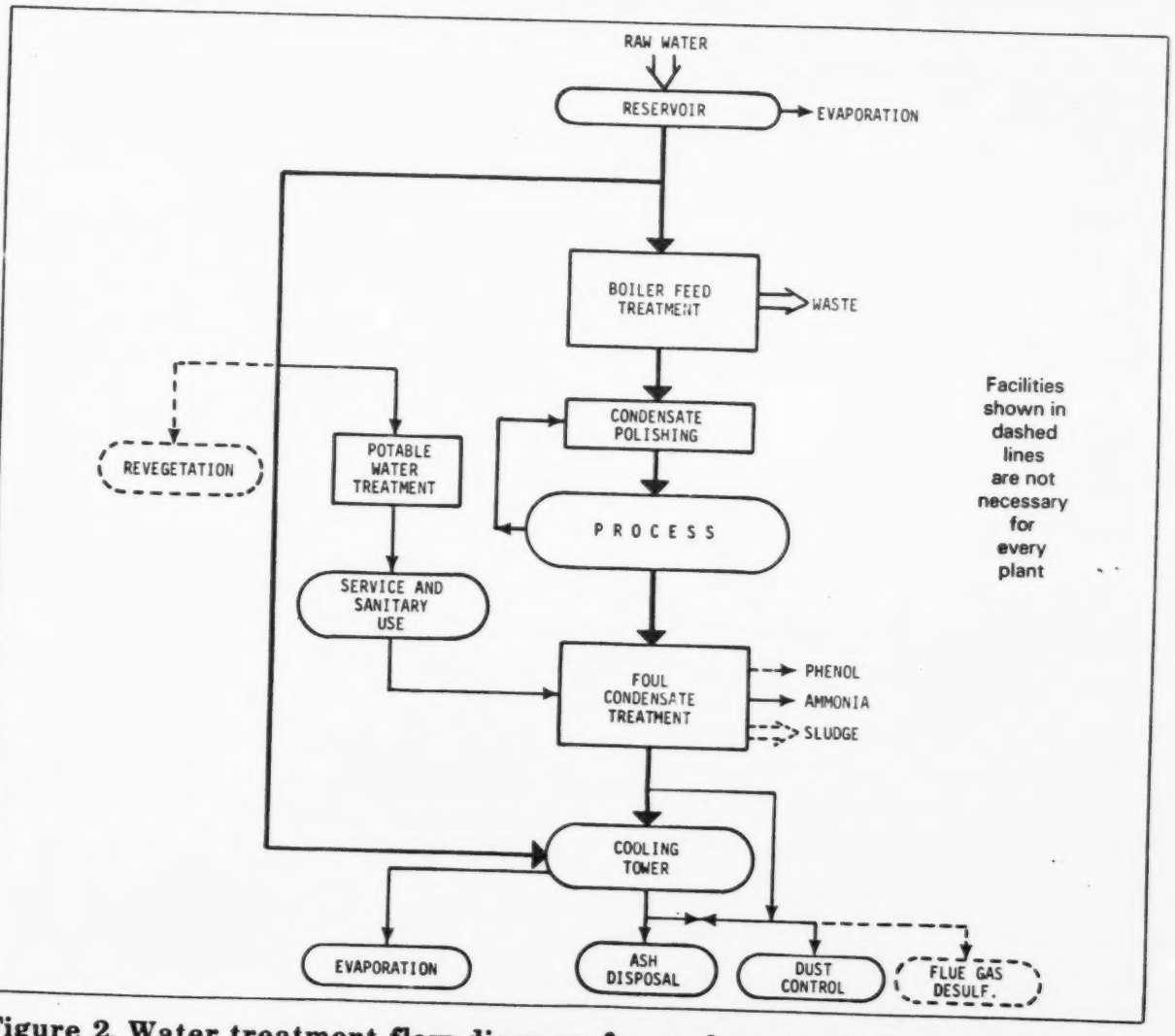

Figure 2. Water treatment flow diagram for coal conversion plant generating dirty process water.

disposed of for coal gasification plants. 1,000 and 4,000 ton/day (900 and 3,600 metric t/d) for coal liquefaction plants, and 2,000 and (6,000 ton/day 1,800 and 5,400 metric t/d) for solvent refined coal. Outstripping all of the coal conversion residuals by an order of magnitude are those from oil shale processing: between 68,000 and 104,000 ton/day (62,000 and 97,000 metric t/d) of wet solids are generated for the three oil shale conversion processes considered here. A summary of the wet-solid residuals generated by each conversion process, normalized with respect to the heating value of the product, is shown in Table 1.

The quantity of the residuals depends on the ash content of coal, the salt content of the source water, and the sulfur content of coal when flue gas desulfurization is used on coal-burning plant boilers. The maximum residuals produced by each process depend on the site.

The largest quantities of residuals for the Lurgi, Hygas, and Synthoil processes occur in areas with the highest ash coals; i.e., in parts of Alabama and Four Corners, New Mexico. For the Synthane and SRC processes, the largest residuals are generated at sites using brackish groundwater. For the Bigas process, the quantities of both ash and flue gas desulfurization sludge determine the sites with the largest residuals.

Except for the Lurgi process, the wet-solids generated by the three other coal gasification processes are relatively insensitive to process. In general, the Lurgi process generates more wet-solids because of the large quantity of boiler feed treatment waste water required. The total wet residuals, normalized with respect to the heating value of the product, are comparable for the Synthoil and SRC processes; the SRC process has a slightly higher value. The larger quantities of wet residuals for coal gasification are attributed to flue gas desulfurization, which is not required for the liquefaction and coal refining processes.

Waste water treatment

In estimating consumptive water requirements and wet-solid residuals, it was assumed that no water streams leave the mine-plant boundaries and that all effluent streams are recycled or reused within the mine or plant after treatment. Water may be released to evaporation ponds as a means of salt disposal. The rest of the water leaves the plant as vapor, as bonded hydrogen after hydrogenation, and as occluded water in the solid residuals The water treatment plants are not designed to return flow to receiving waters. Returning water to a source is not economic when the water must be cleaned to a quality equal to or better than the source water in order to meet environmental regulations.

Cost and energy estimates for water treatment are much less well defined than the water and solid residual quantities. Although the water treatment technologies considered are achievable, experimental evidence for coal conversion process waters is not available to fully assess them. For this reason, designs and costs must be regarded with a greater degree of uncertainty than the estimates of water quantity requirements. Because of the large number of plant-site combinations, all various water treatment options for each plant-site combination were not examined. Instead one or two water flow diagrams, each applicable to one or more processes, were used at many sites.

In any synthetic fuel plant, high quality water is required for the process, intermediate quality is required for cooling, and low quality for disposal and mine uses. The two largest water treatment costs are for the treatment of the raw water to boiler water quality and for the treatment of the low-quality process condensate to make it suitable for use in the cooling tower. The lowest cost is for treatment within the cooling tower.

Figure 2 is a general water treatment scheme for a coal conversion plant generating dirty process water. The scheme is not unique, but does contain the main components of any water treatment plant: Boiler feed water preparation, process water or condensate cleanup, and cooling water treatment. The three main streams are shown with heavy lines. Details of the water treatment block diagrams used for all of the processes are given by Gold and Goldstein. (*1*)

Boiler feed water preparation includes occasional lime soda softening, electrodialysis on all plants when the raw intake water is brackish, and ion exchange. Foul condensate treatment includes phenol extraction, ammonia separation, and biotreatment. Phenol extraction, involving solvent extraction of phenolic compounds in which phenol is recovered and sold to help defray treatment costs, is used only when the foul condensate is highly concentrated. The process was not used for Lurgi or Synthane processes fed by bituminous coal, nor was it used for the Hygas and Bigas processes. Ammonia separation, used for all process-site combinations, is a distillative extractive process, where the ammonia is assumed recovered as a 30 wt % solution and sold to help defray costs. Because of the lack of information on how much organic contamination is acceptable in cooling water, biotreatment is used on dirty condensate from all plants except Bigas. Cooling water treatment involves lime soda softening of the raw water for cooling tower makeup, filtration of the effluent water from biotreatment, acid treatment of all high alkalinity cooling water makeup streams, the addition of biocide anticorrosion chemicals and suspending agents, and lime soda softening of the cooling tower blowdown.

Table 1 also summarizes the costs of water treatment, not including the cost of residuals disposal. The costs of water treatment for oil shale were not calculated. For each process, except Bigas, the largest water treatment cost corresponds to the use of brackish water as a raw water source and reflects the high costs of boiler feed water treatment associated with demineralization. The highest cost is for the Lurgi process; the quantities of steam required and dirty condensate produced are greater than those for the coal liquefaction and coal refining processes. Although the process condensates for these last two processes have the poorest quality, the costs are determined primarily by the quantities of process condensate produced and boiler feed water required, which are quite low for the Synthoil and SRC processes. The cost of water treatment is not expected to exceed 7% of the sale price of the product fuel for any of the plants.

The energy required for the water treatment plants is controlled by the amount needed for ammonia separation, an amount directly proportional to the rate of foul condensate production. Referring to Table 1, the largest energy requirements for any conversion process are for the Lurgi process, followed by the three other gasification processes. Again, the liquefaction and clean coal processes have the lowest energy requirements. Large amounts of energy are also required if electrodialysis is required to demineralize brackish water for boiler feed water. The total energy requirements for the water treatment plants fall in the range of 0.04 to over 8% of the product energy, or about 0.03 to 6% of the energy in the feed coal.

Comparisons with other studies

Table 3 compares the results of the present study with those of two recently published studies in which regional and national fuel production was estimated based on water availability. Except for the oil shale results, which are based on design data, the results of the present study for net water consumed are considerably lower than those of the other two studies. The Lurgi designs of El Paso and Wesco give a net water consumption of 37 and 30 gal/million Btu (133 and 108 m^3/billion kJ), respectively, which are comparable to the high wet cooling estimates of the present study.

Not enough information was provided by Harte and El-Gasseir (*5*) or ERDA (*6*) to explain the widely differing quantities. In a comparison of earlier assessments, however, Goldstein and Probstein (*7*) point out that the principal difference is in the method of estimating the cooling water makeup requirements. Another important difference, although not as important as the difference in the cooling water requirements, is the water consumed for mining, reclamation, evaporation, solids disposal and other uses, which is very much site specific.

In any event, some of the higher estimates of Gibson et al. (*3*) and Berty and Moe (*4*) are unrealistic. For example, for a coal gasification plant designed to be extremely wasteful of water, the total net water consumption could be as high as 100 gal/million Btu (360 m^3/billion kJ), which is about three times the Lurgi design values and about one-half of the largest value shown in Table 3. The largest part is the water consumed for cooling, estimated to be 45 gal/million Btu (162 m^3/billion kJ). This is based on a conversion efficiency of 65% with all of the unrecovered heat dissipated by wet cooling, a condition which is not realistic.

In the Lurgi process, if *all* of the dirty process condensate were to be disposed of by evaporation and not reused in the cooling system, then the total process water consumed would be the total steam fed to the reactors, about 30 gal/million Btu (108 m^3/billion kJ). Mining, flue gas desulfurization, reclamation and all other water requirements should not exceed 25 gal/million Btu (90 m^3/billion kJ).

In a plant designed for a relatively high degree of water reuse and conservation, only about 33% of the unrecovered heat would be dissipated by wet cooling, so that 15 gal/million Btu (54 m^3/billion kJ) would be consumed by cooling, compared to 45 gal/million Btu (162 m^3/billion kJ). All of the process water condensate would be reused and the mining, flue gas, and all other water requirements could be reduced by 75% percent from 25 to about 7 gal/million Btu (90 to about 25 m^3/billion kJ).

The total water consumed for a plant not wasteful of water, but at the same time not designed for minimum water consumption, would be about 22 gal/million Btu (79 m^3/billion kJ), as compared to 100 gal/million Btu (360 m^3/billion kJ) for a plant extremely wasteful of water. Coal liquefaction and coal refining processes are more efficient and do not produce as much dirty condensate so that the high estimates for these processes would be much lower.

Future needs

The water quantity estimates and estimating procedures given in this article and by Gold (*1*) and Probstein and Gold (*2*) are intended for use in determining the water related impacts of coal and oil shale conversion complexes. Some current estimates noted in this article may be considered excessive, thereby producing misleading results. The most reliable engineering designs published to date agree favorably with the range of water consumption given in this discussion.

The major consumptive use of water in coal conversion plants is water evaporated for cooling. Since much of the nation's coal is in areas where water is critically lacking, further study into the methods and cost of conserving cooling water is justified. Investigations of interstage coolers on hydrogen, oxygen, and synthesis gas compressors will require only a small effort and give important guidance.

The quantity estimates made in this article are predicated on complete water reuse. It is probable that technology exists to treat effluent waters adequately. Experimental evidence for treating coal conversion process waters is very limited. The designs and costs must be regarded with a greater degree of uncertainty than the estimates of water quantity requirements. Techniques for treating raw water feed to boiler water quality are well known, as are the techniques for treating circulating cooling water.

One area that requires further investigation, however, is the determination of the level of organic contamination that would be acceptable in cooling towers. The area of research and development requiring the most work is the treatment of condensate waste waters for reuse. These waters are high in phenol, other organic matter, ammonia, hydrogen sulfide, and carbon dioxide. The economics of treatment very much depend on the selection and arrangement of the treatment processes.

The blowdown from the cooling tower may be disposed of with the coal ash or into evaporation ponds. The blowdown stream may contain toxic organics. The organics of concern are primarily the 65 compounds or classes of compounds referenced in Title 3 of the Water Pollution Control Act, as amended (XXXIII, U.S.C. 466, etc.). Unless properly treated, water and/or air discharges contaminated with organic materials may pose the greatest potential threat to the environment from the emerging energy technologies. #

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